# NAVAL POSTGRADUATE SCHOOL

**MONTEREY, CALIFORNIA**

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## MBA PROFESSIONAL REPORT

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**Demand Response at the Naval Postgraduate School**

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**December 2008**


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The purpose of this MBA project is to assist the Naval Postgraduate School's Public Works department to assimilate into a Demand Response program that will not only benefit the school but also the community. Demand Response programs are open to any residential or business customer that is tied into a local power grid. Through varying Demand Response programs, the Naval Postgraduate School has the potential to help the local power grid by curtailing energy consumption during peak times and in return benefiting from rebates and support services that can help to adopt better energy saving practices.

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**DEMAND RESPONSE AT THE NAVAL POSTGRADUATE SCHOOL**

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Submitted in partial fulfillment of the requirements for the degree of

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# DEMAND RESPONSE AT THE NAVAL POSTGRADUATE SCHOOL

## ABSTRACT

The purpose of this MBA project is to assist the Naval Postgraduate School's Public Works department to assimilate into a Demand Response program that will not only benefit the school but also the community. Demand Response programs are open to any residential or business customer that is tied into a local power grid. Through varying Demand Response programs, the Naval Postgraduate School has the potential to help the local power grid by curtailing energy consumption during peak times and in return benefiting from rebates and support services that can help to adopt better energy saving practices.

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## LIST OF ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| AUTO DR | Automated Demand Response |
| CAISO | California Independent System Operator |
| CBA | Cost Benefit Analysis |
| CPP | Critical Peak Pricing |
| DESC | Defense Energy Support Center |
| DOE | Department of Energy |
| DR | Demand Response |
| EBEC | Business Energy Coalition |
| DRRC | Demand Response Research Center |
| E-DBP | Demand Bidding Program |
| EMCS | Energy Management Control Systems |
| ENERNOC | Energy Network operation Center |
| EPACT | Energy Policy Act |
| ESPC | Energy Savings Performance Contract |
| FEMP | Federal Energy Management Program |
| FAR | Federal Acquisition Regulations |
| IGA | Investment Grade Audit |
| ISO | Independent Service Operators |
| kWh | Kilowatt-hour (one thousand watt-hours) |
| LSE | Load Serving Entities |
| MW | Mega Watt |
| NPS | Naval Postgraduate School |
| PG&E | Pacific Gas and Electric |
| RTO | Regional Transmission Organizations |
| RTP | Real Time Pricing |
| TOU | Time of Use |
| UESC | Utility Energy Service Contract |

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# I. INTRODUCTION

## A. PROLOGUE/PURPOSE

Demand Response (DR) is the proactive reduction of electrical consumption by utility customers through curtailment and/or self-generation in response to system resource capacity needs, system reliability events, or extreme wholesale electricity prices. By doing so, Demand Response answers the supply and demand issues and helps to provide a win/win situation to the utility provider and the customer.

Demand Response programs have become increasingly popular in all economic sectors. The programs have grown out of the need for increased energy efficiency. Public, private and federal energy customers have felt the energy crunch for several years and recently the vice has tightened, and the demand for energy is greater now than ever. Technology is available to assist both the utility provider and customer with energy conservation and demand alternatives. Consumers are just beginning to realize the savings that they can make by using existing technologies.

A Demand Response contract gives the consumer the ability to work with the utility provider in developing a program that enables both parties to experience positive gains. Through Demand Response contracts and advance metering, consumers are able to manage their energy consumption and thus reduce their costs. More importantly, Demand Response programs enable utility companies to meet energy requirements during peak operation times.

Peak operating times are critical because of the high demand for energy when a grid is most susceptible to a black out or brown out situation. These times usually occur between May and October during the weekday between 1100 and 1800. To prevent this, utility companies have developed Demand Response and energy conservation programs to help them remain operational and reduce their risks during peak times.

The Federal Energy Regulatory Commission (FERC) has jurisdiction over utility industries and mandates that all grids are operational and meet reliability standards set forth by the commission. In order for utility companies to adhere to the rules set by FERC during peak times, they may have to start up additional peak performance plants to meet demand. Not only are these plants extremely expensive to startup and maintain, they also cause tremendous amount of pollution for the few hours of operation. Therefore, it is very important to meet peak power requirements during peak time without resorting to the backup plants.

By creating stability through Demand Response and energy conservation programs, both customers and utility providers obtain benefits that include improved system reliability and customer service, cost avoidance of starting extra power plants during emergencies, and reduction of negative environmental impact.

The illustration below shows a graphical depiction between standard energy consumption, energy efficiency and Demand Response for a 24-hour period. The graph shows that Demand Response can be applied to standard and energy efficient industries during the peak hours of 1300 to 1700 with slightly larger reductions when applied to standard consumption.

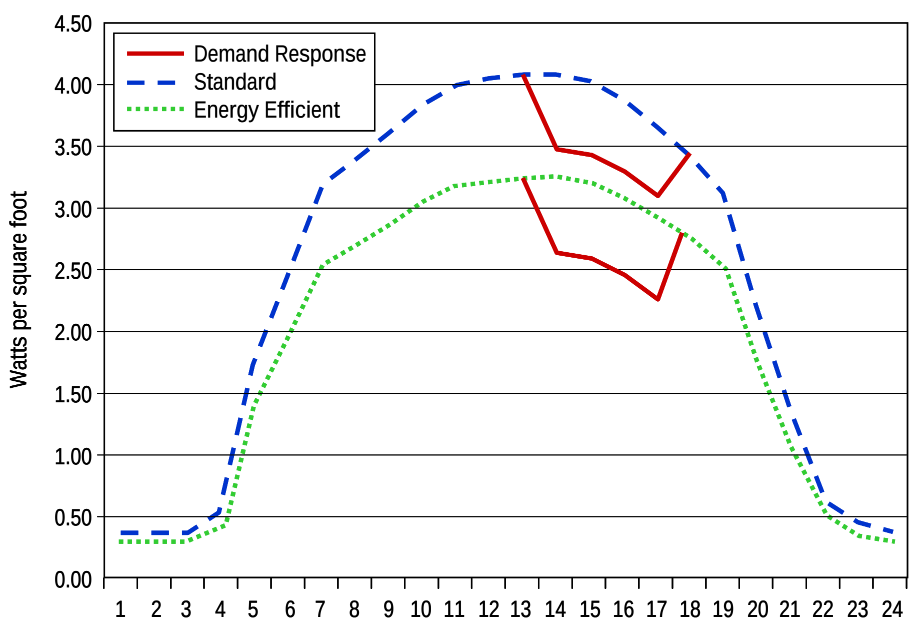


Figure 1. Graphical Depiction of Demand Response vs. Energy Efficiency

The decision to replace an incandescent light bulb with a compact fluorescent is an example of typical energy conservation efforts. Energy efficiency and conservation are important components of the implementation of a Demand Response program. The focus of this report is to examine its feasibility and provide explicit recommendations for a Demand Response program at the Naval Postgraduate School. This report will also serve as a model for other military installations that are interested in adopting a Demand Response program.

## B. TYPES OF DEMAND RESPONSE PROGRAMS

Demand Response programs are typical categorized into two broad categories, incentive based programs and time-based demand programs. The common features of both types are that they are active customer responses to Demand Response events. They contrast in that incentive based programs are contractual agreements that define an actual quantity to curtail whereas time based programs are adjustable rates that allow customers to adjust usage based on price without curtailment agreements. The changes in electricity usage are designed to be short-term, centered on critical hours during the day or year when demand is high, or when reserve margins are extremely low. The previously mentioned categories are further discussed in relation to sub categories of each.

### 1. Incentive Based Programs

Incentive based programs give customers load-reduction incentives that are separate from the retail rate, which may be fixed (based on average costs) or time varying. The load reductions are needed and requested either when the grid operator thinks reliability conditions are compromised or when prices are too high. Some incentive-based programs penalize customers that enroll but fail to respond or fulfill their contractual commitments when events are declared.

***a. Direct Load Control*** - program that allows load serving entities (LSE) or Demand Response service providers to control user load by directly cycling discretionary load of certain end uses, directly turning off such loads, or implementing custom load control strategies that reduce peak usage.

***b. Interruptible or Curtailable Rate*** - Rates that provide a rate discount to reduce curtail energy during system contingencies with heavy penalties if not curtailed. Interruptible programs are commonly used amongst large commercial or industrial companies.

***c. Demand Bidding or Buyback Programs*** - Bids are placed based on wholesale electricity market prices on the curtailment of large customers. Large customers are consumers that use more than 1 MW.

***d. Emergency Demand Response*** **-** programs that provide incentive payments when reserve shortfalls arise but curtailment is strictly voluntary with no penalties involved.

***e. Capacity Market Programs*** **-** customers offer predefined load reductions and are penalized when they cannot meet curtailment. Eligibility requirements for the program are based on demonstrating sustainable and achievable reductions.

***f. Ancillary Services Market Programs*** - customers bid load curtailments in independent service operators/regional transmission organizations (ISO/RTO) markets as operating reserves. If their bids are accepted, they are paid market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the market energy price.

### 2. Time-Based Rate Programs

The second form of Demand Response is time-based rate programs. These programs expose customers to varying levels of price exposure that are based on blocks times that customers are to be notified and the curtailment period.

***a. Time of Use Programs (TOU)*** - TOU programs provide customers with average prices during a block of time within a 24-hr period.

***b. Real Time Pricing (RTP)*** - RTP programs offer rates in which the price for electricity fluctuates hourly reflecting changes in the wholesale price of electricity. Customers are typically notified of RTP prices on a day-ahead or hour-ahead basis.

***c. Critical Peak Pricing (CPP)*** - CPP rates are a combination of the TOU and RTP. The difference is normal peak price is replaced with a much higher CPP during a DR event.

## C. EARLY EXPERIENCES WITH DEMAND RESPONSE

For many years large industrial and commercial companies were called upon by energy providers to establish innovative techniques to reduce the amount of power their companies required. Demand Response basically consisted of companies turning off lighting and shutting down non-vital motors or equipment during peak times. This early strategy of Demand Response was known as interruptible power supply.

During the early stages of Demand Response, customers would completely shutdown operations in a curtailment situation. Large companies were given electrical rates that were lower than industry standard in exchange for the energy reductions. One of the greatest problems with interruptible rates programs was that utility providers rarely requested companies to reduce loads and those rates soon became the industry standard for large industrial and commercial companies. The harmonious relationship between energy providers and large companies ended when power requirements increased faster than power production.

During the late 1970s, Pacific Gas and Electric (PG&E) had an initiative that involved firm and non-firm discounts for Demand Response. Non-firm rates provided lucrative discounts for companies that could curtail energy. Customers involved in non-firm curtailment would curtail power down to contracted firm rates during Stage 2 electrical emergencies for a specified period of time. Stage 2 Emergencies indicates that operating reserves are forecasted to be less than five (5) percent. PG&E Non-firm customers are required to curtail their electric load down to their contracted Firm Service Level, while, all other customers are requested to voluntarily curtail nonessential electric loads. A complete table of PG&E's curtailment stages can be found in Appendix A.

The 2001 California power outage is probably the most influential incident that brought national attention to the importance of Demand Response. Because of an increase in demand for power, energy price regulations, and partially deregulated California energy system suppliers were forced to ration their electricity supply rather than expand production. This rationing was directly related to price controls instituted by the state which intern caused utility companies to pay more for electricity than they could charge customers. Customers that participated in the non-firm Demand Response program were then called upon to curtail energy according to their contract and reduce usage to firm pricing standards. The problem that existed was customers failed to do so because they had become accustomed to the status quo. Because of the inefficient initial DR program rolling blackouts ensued putting over 97,000 customers in the dark and causing a state of emergency.

# II. LITERATURE REVIEW

## A. FOREWORD

This chapter presents a review of pre-existing research and ideas about Demand Response initiatives, which includes current public policy decisions and controversial topics in DR. In addition, it presents contrasting perspectives and points of view on the topic, analyzing strengths and weaknesses of these studies. The final phase of the chapter discusses future research and innovation required for implementation of Demand Response.

## B. PUBLIC POLICY DECISIONS ON DEMAND RESPONSE

The most substantial policy that affects the implementation and development of Demand Response programs in the United States is the Energy Policy Act of 2005. The Energy Policy Act (EPAct 2005) is an attempt to prevent growing energy concerns of the 21$^{st}$ century by changing the antiquated previous energy policy and providing tax incentives and loan guarantees for the production of various energy types. More specifically, section 1252 (e)(3) requires that the Federal Energy Regulatory Commission (FERC), under the guidance of the Department of Energy (DOE), to prepare a regional report that evaluates electric Demand Response programs from all consumer classes. The Energy Policy Act (EPAct 2005) directs the FERC to concentrate on the following when producing reports to Congress:

1. Background on DR and examination of benefits associated with DR programs.

2. Conduct analysis on the saturation and penetration rate of advanced metering and communications technologies from the national level to the customer classes. In addition, conduct cost benefit analysis associated with the deployment of advance metering.

3. Conduct an extensive review of existing DR programs and time based rate programs.

4. Conduct a review of the size of DR as an annual resource in Megawatts (MW) contributed.

5. Consider the potential and role of DR as a quantifiable and reasonable source for regional planning purposes.

6. Summarize and analyze the regulatory barriers to improve customer participations in Demand Response, peak reduction and critical period pricing programs.

The most recent report conducted by the FERC commission released in August 2006 (FERC 2006) indicated that approximately 530 entities operate at least one type Demand Response program out of the 2,620 entities that responded to the survey. The total potential peak reduction for those 530 entities is 29,655 MW which accounts for only four percent of the electricity demand for the summer months. The most surprising information retrieved from the survey is industrial and commercial customers account for only 16 percent of the Demand Response resource potential at the national level. The lack of participation is caused by a range of barriers that include cost recovery of technology to lack of coordination between federal and state jurisdictions affection Demand Response. One particular item that was not discussed is the provision where all federal facilities are to have metering capabilities—and to the extent practical, advanced meters or advanced metering devices by October 1, 2012(EPACT 2005). FERC should explore the possibility of conducting Demand Response audits on Federal facilities to ensure they are complying with EPACT standards.

## C. CONTROVERSIAL ISSUES RELATED TO REAL TIME PRICING PROGRAMS

Real time pricing programs are a type of time based rate DR program, that focuses on the price changes of electricity rather than target and track specific amounts demand reduction like demand-bidding programs. Sioshansi and Vojdani (2001) raises strong objections about the distinction between RTP and DR programs and propose that these programs in all actuality are not DR programs at all. Their argument is based on the fact that DR programs goes beyond RTP in the sense that it attempts to buy back demand which has already been sold to effectively alleviate congestion by rationing scare capacity during peak demand periods. The authors argues that RTP is not DR, but merely information communicated to consumers about the wholesale market price of energy during various time of the day providing an incentive for customers to change their usage and not curtailment.

Barbose, Goldman and Nenan (2004) review the experiences of 43 voluntary RTP programs offered in 2003 by utilities across the U.S. They find that the RTP programs in their survey have achieved very unfavorable reviews and have not produced successful results. The findings of their survey include:

1. Approximately one third of the programs are being phased out, with the remaining two thirds either being revamped under future program development or not being actively promoted because they are not a viable form of DR.

2. Participation in most RTP programs has been relatively low. Two thirds of these programs included in the survey have fewer than 25 customers and less than 50MW of aggregate peak demand enrolled.

3. Participation in RTP programs is declining; many programs experienced tremendous decrease in enrollment in most recent years.

Advocates point out a variety of barriers towards greater implementation of RTP. Costello (2004) argues that the primary barrier is the enrichment of average cost pricing in the regulatory arena. Regulatory authorities tend to be risk averse and view RTP as too risky for many customers. Many utility companies view RTP as too risky for their operations because it may create uncertainty about cost recovery as well as possibly incurring greater numbers of customer’s complaints. Finally, Costello suggests that customers themselves may be the biggest barriers to RTP for being too complicated, forcing them to keep track of something most do not already do. Regulators, utilities and Independent System Operators (ISO) that believe once the barriers described by Costello are removed RTP will help revolutionize the way electricity is priced.

## D. MODERNIZATION FOR THE IMPLEMENTATION OF DR

California utilities have been exploring the use of automated Demand Response programs to reduce peak day summer time electric loads. The purpose of auto DR is to improve the responsiveness and participation of electricity customers in DR programs and lower overall costs to achieve DR. Recent experience has shown that customers have limited knowledge of how to operate their facilities to reduce their electricity costs (Quantum and Summit Blue, 2004). While the lack of knowledge about how to develop and implement DR control strategies is a barrier to participation, another barrier is the lack of automation in DR systems. Most DR activities are manual and require building operations staff to first receive emails, phone calls, and pager signals and second, to act on these signals to execute DR strategies. There are three levels of DR automation, described below.

1. Manual Demand Response- a labor-intensive approach such as manually turning off or changing comfort set points at each equipment switch or controller.

2. Semi-Automated Demand Response- involves a pre-programmed Demand Response strategy initiated by a person via a centralized control system.

3. Fully Automated DR- it does not involve any human intervention, but it is initiated at a building or facility through receipt of an external communication signal.

The last of the three is regarded as Auto-DR and considered the new way of technology in DR programs. In order for customers to take advantage of an Auto-DR program there first has to be an energy management system (EMCS) installed. EMCS are centralized controls, with computer interface, primarily for heating, ventilations and air conditioning systems. Utilities providers or ISO’s form a direct interface with the EMCS and send a signal to initiate load shedding by dimming or turning off non-critical lights, changing comfort thermostat set point or turning off non-critical equipment. Figure 2 is a typical example of how an Auto-DR program interacts with an EMCS.

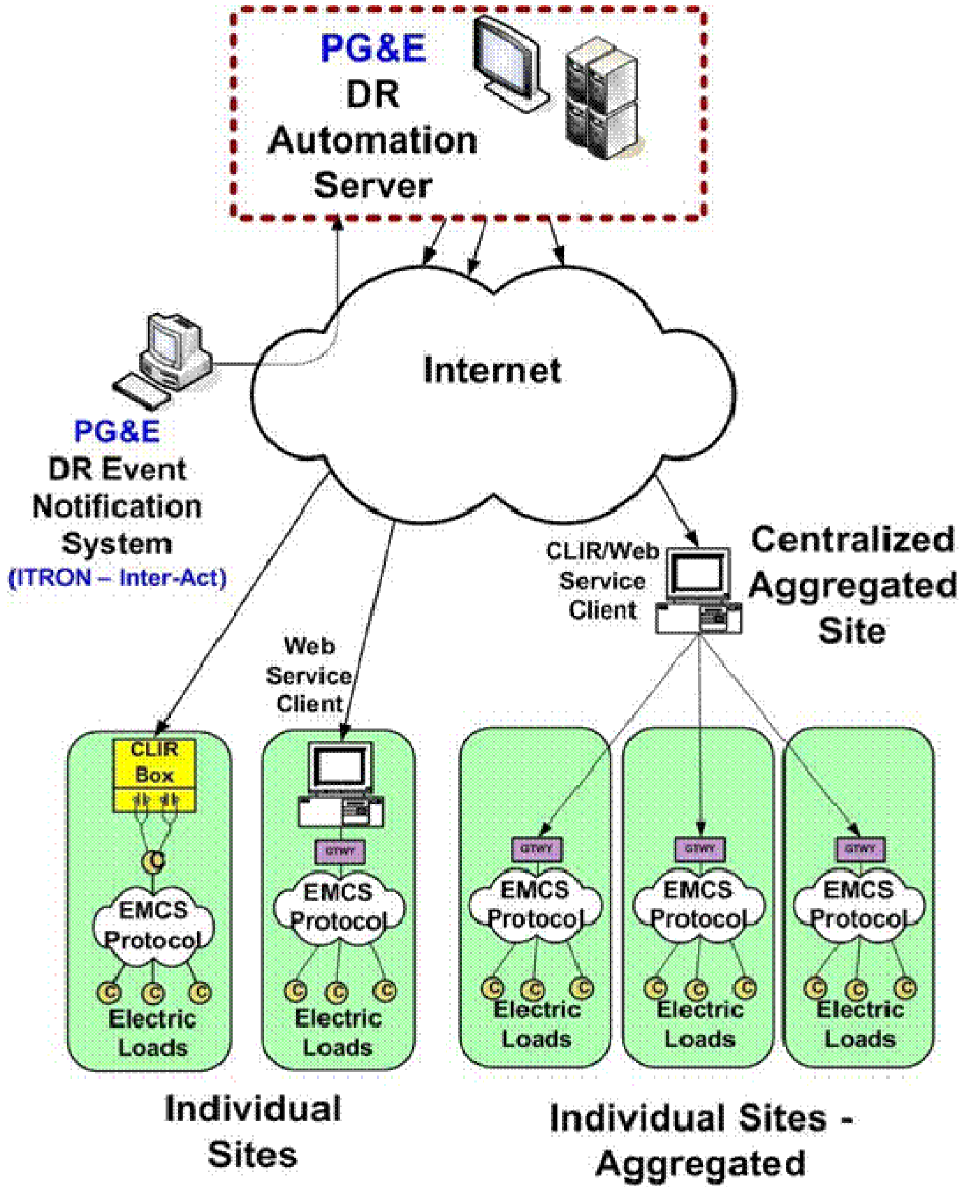


Figure 2. Example of Auto DR System with EMCS

A most recent study of five facilities involved in Auto-DR evaluated by Demand Response Research Center (DRRC) (Piette, Sezgen, Watson, and Motegi 2005) in California reveals several lessons that are important to consider for application of Auto-DR Programs. The key issues are as follow:

1. **Fully automated DR is technically feasible with minor enhancements to current state-of-the-art technology –** All facilities had previously installed EMCS. Implementation of Auto-DR programs was less than one month with some only requiring one day, requiring programming software and minimum installation of hardware at all five sites.

2. **New Internet technology enhances the capabilities of existing building systems to enable Demand Response** – Although each of the five facilities had different EMCS, they could easily be unified through the use of enabled web services to respond to signal from energy providers.

3. **Automation enhances Demand Response programs –** Automation is likely to increase the number of times a facility is willing to shed load and the number of facilities involved in DR, by decreasing the effort to prepare for a DR event

4. **Large facilities support the objectives of DR –** The energy managers at the five facilities believe that DR programs will increase in their importance and prominence, and new technology will assist them in participating in these programs.

5. **New knowledge is needed to procure and operate technology and strategies for DR –** Facility operators need to better understand DR economics, controls, communications, energy measurement techniques, and the relation between changes in operation and electric demand or outsource the responsibilities to third party aggregators.

Baskette (2007) gives a very in-depth summation about the importance of automated DR for large and medium-sized customers and what value does this brings to the electricity system and to the end use customers. Baskette's argument is based on the premise that automation can take the hassle out of participating in a Demand Response program and reduce the potential of an organization being penalized for non-compliance due to staff personnel being unavailable during a Demand Response event.

## E. SIGNIFICANCE OF THIRD PARTY DR SERVICE PROVIDERS

Third party DR service providers are companies authorized by utilities companies to act as an intermediary between the customer and the utility company to provide demand capacity. A recent report to the California Energy Commission encouraged more participation of third-party aggregators in the Demand Response market because it resulted in more feet on the street than the Load Servicing Entities (LSE) outreach and marketing efforts alone can contribute (Faruqui, Hledik, Newell, and Pfeifenberger 2007). They also state that aggregators are in the business of educating customers on the benefits of Demand Response and how best to participate in the numerous program options available to them that best fit their operations. This could be as simple as adjusting an existing energy management system to changing business processes and installation of new hardware while not adversely affecting business operations. In addition, LSEs or California Independent System Operator (CAISO) need to have multiple programs or products to meet the operational requirements of specific systems but often this is too much information for customers to determine how to participate.

End-use customers working with third party aggregators can rely on their aggregator to enroll them in a program that best fits their load reduction capabilities and reduce the risk of penalties by employing a financial management portfolio strategy. Baskette (2007) suggests that under this strategy the aggregator spreads the risk by enrolling more customers than required if all performed at 100%. This allows some to under perform and other to curtail more. The end result is that LSEs or the ISOs receive reliable, dispatchable, and cost-effective load reductions, while the end-use customers are more likely to participate in the programs because they are shielded from potential underperformance penalties. Moreover, Baskette (2007) states that while utilities companies have been actively conducting Demand Response programs and pursuing new avenues for reducing peak load; this activity is not core to the utility business but should be left to aggregators whose primary business is to realize reliable peak load reductions for LSEs.

While aggregators do provide a significance service, this does not go with out a cost to their customers. The costs are not typically seen by the customer because they are usually deducted from the incentives that customers receive in the form of rebates for participating in DR programs, which the aggregators has dictated. One particular installation that requested to remain nameless entered into a contract with a third party aggregator that cost them $30,000.00 (40%) of their annual incentive rebate. In most utility markets, aggregators do nothing more than sale services, that previously exist, by focusing on customers ignorance or fear or incurring penalties. If customers did their required homework, which entails understanding their peak usage during the critical time-frame for a DR event, the amount they could curtail along with the reaction after notification, there would not be a need for the assistance on an aggregator. With this small level of preparation, customers would be able to enter programs and not incur the dreaded penalties that aggregators focus on to sale their service. In some markets, particularly the PG&E programs there are several options that do not have penalties associated with the programs, but the rebate incentives are smaller than those that penalize.

## F. THE STATE OF TECHNOLOGY IN DR

A key requirement for most Demand Response programs and time-based rates is the availability of enabling technology. For utilities and end use customers to implement Demand Response and time-based rates, customers would need meters that record usage on a more frequent basis, preferably hourly (Ptiette and Kilccotte, 2006). Introducing other demand technologies such as smart thermostats (i.e., thermostats that adjust room temperatures automatically in response to price changes or remote signals from system operators) would increase the amount of load that could be reduced under a Demand Response program. Advances in integrated circuitry, control systems, and communications technologies have significantly increased the functionality of advanced metering and Demand Response technologies. These advances have the potential to provide more power system and societal benefits than those achievable with existing Demand Response programs. They make customer responses possible in more situations, allowing both greater customer receptivity and higher utility confidence that customers can and will respond to Demand Response.

As for the state for the state of technology today recent advances in information and communication technologies have expanded metering functionality, and increased the potential for lower metering costs but not to the point where utilities are enthusiastic to undertake significant investments. According to the FERC 2006 survey advanced metering has an overall market penetration value of only 5.9%, a percentage that will have to rise dramatically for Demand Response to reach its full potential. While improving market penetration for advanced metering the communication technologies for notifying customers will also have to be reinforced to allow a greater likelihood of response either through pager, cell phones, internet or other means.

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# III. METHODOLOGY

## A. BACKGROUND

The Naval Postgraduate School has the ability to reduce power during demand times. For fiscal year 2007 the school used approximately 34,000,000 kWh of power. This energy consumption can be tailored down during peak demand times to answer the call in a Demand Response situation. The school can commit to a DR program through its Energy Management System, which enables it to reduce power through predictable means.

Which Demand Response program is the most beneficial in terms of relative value to the Naval Postgraduate School? To answer this question, a cost benefit analysis (CBA) was constructed. Our cost benefit analysis model is based off of the methodology described by Anthony Boardman in his CBA studies (Boardman, Greenberg, Vining, 1996). We present the steps that are relevant to our analysis.

## B. STEP 1: BENEFITS AND COSTS COUNT

To begin the CBA, it is important to determine whose benefits and costs count. The environment and local populace are both benefactors. The other benefactors are the customer and the provider.

The costs that count are the ones that the provider and customer must pay. The provider does not worry about the cost to the customer and vice versa. The incentive or rebate given to the customer must be less than the savings and benefits given to the provider.

The customer could incur investment costs. If there is not a proper energy management system in place, then the provider or aggregator will have to install meters to assist Demand Response in an accurate and timely manner. Depending on which program the customer selects, these costs may be financed from the rebate or may need to be paid up front.

The benefits and costs of a Demand Response program that count are therefore experienced by both the power provider (PG&E) and the customer (The Naval Postgraduate School). The second step is identifying the possible alternatives or varying degrees of Demand Response programs that are available.

## C. STEP 2: BENEFITS AND COSTS

Demand Response programs are offered through the energy provider as well as aggregate providers. Both the energy provider and the aggregator offer a variety of options in a Demand Response program. The differences between the programs are various alternatives that each program has. The following alternatives within each program will be the ones we will concentrate on for this step.

Operating months – most Demand Response programs can occur between May and October; however, some are active throughout the year.

Curtailment window – the timeframe over which the customer can expect to curtail energy.

Notification time – usually the shorter the notification time the higher the rebate.

Curtailment level – can be pre-determined or on a best case scenario.

Incentive Payment – is based on the curtailment level and the amount of notification time.

Non-compliance penalties – if a customer does not meet the curtailment amount that has been agreed to with the energy provider during the curtailment window, then a penalty is incurred.

Meter requirements – Demand Response programs require advanced metering capabilities. Installation of these meters depends upon actual energy consumption for the customer.

When going through the alternatives the goal is to maximize the expected value as it relates to cost and benefits. The goal is minimal costs with the maximum amount of benefit.

Each program and its alternatives will have impacts and measurement indicators. These two factors are addressed in Step 3.

## D. STEP 3: IMPACTS AND MEASUREMENT INDICATORS

The impact to the local grid is present with any alternative. Each alternative indicates the trade-offs associated with the choices that the Naval Postgraduate School makes to curtail energy consumption during peak times and thus increases the chances that a peak performance plant does not have to be turned on. Refraining from starting a peak performance plant means less pollution and lower environmental impact.

Operations at the Naval Postgraduate School must be managed to sustain minimal impact from any particular Demand Response program.

## E. STEP 4: PREDICT QUANTITATIVE IMPACTS OVER THE LIFE OF A DEMAND RESPONSE PROGRAM

A Demand Response program provides future benefits to the provider and customer. The provider experiences the benefits of having another reliable customer on its Demand Response list so that peak performance requirements are accordingly lessoned.

The consumer benefits through continuous rebates and savings. These savings can ultimately be contributed to energy efficiency and conservation technologies or improvements. Efficiency and conservation technologies will assist the consumer in becoming a more energy conscious user and this will result in more savings for the consumer.

Additionally, a consumer that is enrolled in Demand Response is able to reduce strain on the grid and positively affect the environment.

## F. STEP 5: MONETIZE ALL IMPACTS

The environmental impact that a Demand Response program has is an intangible one. Over time, the energy provider is able to build a costumer base that is reliable and is able to meet curtailment efforts during peak times of demand. This results in less reliance on peak plants and a more energy conscious customer resulting in a more energy aware populace. These impacts may be measureable in terms of building and maintaining peak performance plants. However, they are not being considered in this study.

Each Demand Response program does have a monetary rebate or incentive that is based on energy curtailment by the consumer and the notification time. The actual amount of possible energy curtailment depends on several factors, including the consumer's current energy usage and the buildings or infrastructure that makes up the consumers profile. A dollar value will be able to be assigned to each Demand Response program by analyzing the factors previously mentioned in Step 2.

## G. STEP 6: DISCOUNT RATE AND PRESENT VALUES

Step 6 is not included in our analysis. In Boardman's CBA this is described as follows: "the social discount rate is the rate at which analysts should discount the benefits and costs accruing at different times."( Boardman, Greenberg, Vining, Weimer) Since there is not an actual rate the discount rate will not be included. The present value of each program is simply the current value of the incentive. This value will be addressed in Step 7.

## H. STEP 7: ADD UP THE BENEFITS AND COSTS

This step is the sum of all the benefits and costs. Depending on the Demand Response program in question, there may be various associated benefits and costs.

## I. STEP 8: PERFORM SENSITIVITY ANALYSIS

For comparison purposes between the alternatives the study is conducted with one specific energy curtailment amount. This amount of curtailment will be chosen based off of the school's ability to self generate power and perform basic curtailment measures. The two types of curtailment will reduce the assumption about the amount of curtailment possible and will therefore alleviate the need to perform a sensitivity analysis test.

The amount of curtailment cannot have an overall negative impact to the school. The daily schedule at the Naval Postgraduate School must continue. For this reason large, unacceptable amounts of power reduction will not be considered.

## J. STEP 9: RECOMMENDED ALTERNATIVE

The recommended alternative will take all of the above factors into consideration and will encompass a well thought out choice. This will be considered a recommendation and not a decision on our part. The purpose of this CBA is simply to advise the Public Works Department at the Naval Postgraduate School of the best Demand Response alternative there is as far as expected value is concerned.

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# IV. ANALYSIS

## A. OVERVIEW

This chapter analyzes available Demand Response programs using the methodology described previously. There are several Demand Response Programs available for the customer. The description and requirements vary for each one however, there are many similarities. For the cost-benefit analysis, four programs are compared to identify their relative expected value, and the one that provides most benefits to the Naval Postgraduate School.

Pacific Gas and Electric offers the Demand Bidding Program (E-DBP), Peak Choice, and Business Energy Coalition (E-BEC). The fourth program is offered by ENERNOC, an aggregator that provides Demand Response services. The three programs supported by PG&E require a minimum of 200kW curtailment. The aggregator-based program does not have a minimum requirement.

By reviewing previous electrical consumption data, we derived that the Naval Postgraduate School is able to shed approximately 200 to 300 kW during a peak period. We decided to use 200 kW for a six-hour curtailment period as our baseline to determine the actual value of the rebate amount the school will earn. To further our analysis we have determined from previous Demand Response history in the area there are approximately seven curtailment periods per season.

The Naval Postgraduate School can curtail consumption with self generation and basic curtailment. Self generation is accomplished through the use of backup generators. Basic curtailment is more focused on dynamic solutions. Basic curtailing is made possible through the conscious shut down of unnecessary lighting or consumption, turning up cooling points or numerous other methods.

Static curtailment or a more permanent type of sustainment consists of energy conservation measures. These measures include methods like changing to more efficient lighting, using more energy efficient cooling systems, low wattage light bulbs, occupancy sensors, door and window seals or other methods that require more commitment over a longer period of time.

The curtailment amount has been validated by the personnel in the Public Works department. The amount of curtailment is not threatening to normal day operations at the school. However, the curtailment amount is not something that could be sustained on a daily basis and does not fall into the realm of energy saving for an indefinite amount of time.

## B. NAVAL POSTGRADUATE SCHOOL AUDITS

On July 22, 2008 an initial audit meeting was held between the Naval Postgraduate School (NPS) Public Works department, PG&E, an approved auditing agency and an energy efficiency firm. Pacific Gas and Electric arranged this initial audit in conjunction with NPS. The purpose was to help NPS identify potential energy conservation steps that could save energy and ultimately money.

Pacific Gas and Electric has established relationships with energy efficiency firms in order to provide assistance to businesses, schools, federal institutions etc. These types of customers are usually medium and large sized businesses. The audit serves as a learning opportunity for the customer so that they can become more energy conscious. By promoting energy conservation, utility companies reduce their overall cost by not having to maintain costly back up plants and lowering the consumption and price for customers as well.

In this meeting the energy audit entity spoke to the group about several steps that can be taken to initiate the energy conservation efforts. The initial audit produces surface type fixes to conserve energy which involves energy efficient lighting, lighting sensors in restrooms, etc.

It takes time to execute the audit. It is a phased process that evolves from building to building according to pre-established priorities. The customer, Naval Postgraduate School, is responsible for establishing the audit's evaluation criteria.

Without the determination of improvement targets, such as energy reduction goals, and reduction limits of affected buildings, the audit is not effective.

Buildings are not necessarily identified by the total square footage but more by the actual usage of energy. At NPS, many of these high output buildings reside with the Fleet Numerical Meteorology and Oceanography Center. High output buildings will offer a good look at possible Demand Response targets that could immediately drop loads in times of curtailment.

Following this audit is an Investment Grade Audit (IGA). Future projects that could reduce energy consumption in the long run are identified through the IGA. Specific corrections are brought forward and solid figures are developed that can ultimately be used in actual contracts. This IGA is not a complimentary audit and does get billed to the institution. To pay for the Investment Grade Audit, PG&E can both assume the cost and subtract it from the savings that will be returned, or the audit costs can be rolled into the overall project costs.

Federal law requires that all projects are funded before launch. The Federal Energy Management Program (FEMP) under the Department of Energy has developed the Utility Energy Service Contract to fund federal institutions to implement energy efficiency and renewable energy projects through partnerships with the utilities. "With a UESC, the utility typically arranges financing to cover the capital costs of the project. Then the utility is repaid over the contract term from the cost savings generated by the energy efficiency measures. With this arrangement, agencies can implement energy improvements with no initial capital investment; the net cost to the Federal agency is minimal, and the agency saves time and resources by using the one-stop shopping provided by the utility." (DOE 2008) Federal agencies are encouraged to participate in these energy efficiency programs by the Energy Policy Act of 1992.

Another possible contracting avenue also with the FEMP is the Energy Saving Performance Contract (ESPC). This contract also allows no upfront capital costs. "An ESPC is a contracting vehicle that allows agencies to accomplish energy projects for their facilities without up-front capital costs and without special Congressional appropriations to pay for the improvements." (DOE 2008)

Both of these contracting vehicles provide NPS with additional resources to help conserve energy over the long run. A Demand Response program, if identified correctly, can help to provide funds for future energy conservation contracts.

## C. SIMILARITES IN PROGRAMS

Though the programs are different, many of the steps in the cost benefit analysis are similar. These steps are explained first. The steps that have differences are discussed as a group according to each specific program

### 1. Step 1

Step 1 describes the benefits and costs that count. Benefits for each program are economical, environmental and monetary. Economically speaking, the provider and the energy user both experience a shift in supply and demand. The user reduces demand by curtailing energy consumption and the provider has an increase in their available supply of energy and is then able to meet other demands on the grid.

Costs are equivalent across the spectrum. Each program pays for the necessary metering that must be installed in order to assist the Demand Response plan. This may not be the case in some instances for other users. However, since the Naval Postgraduate School is able to curtail more than 200kW it is exempt from metering costs

### 2. Step 3

Impact to the environment and the local community are equivalent across all programs. If NPS does need to use generators to meet curtailment requirements, the generators will produce a limited amount of impact on the environment. Additionally, the generators need to be started up on a regular basis for maintenance. These startups can easily become part of curtailment period. The result of curtailment means that the local utility company reduces the chances of having to start up a peak performance plant to meet demand. Environmentally speaking the deletion of the start up of a peak performance plant greatly reduces emissions. The local community also feels the impact because it reduces the need for additional infrastructure and electric rates remain lower.

Curtailment could possibly have a negative impact on the school. This has been mitigated by the various means of self generation and basic curtailment methods. However, minimal power interruptions and various small nuisances could be experienced.

The measurement indicators are expressed by the kilowatt usage on the utility bill, the incentive payment and changes in the electrical rate. Some of these measurement indicators will not be evident right away. However, the rebate check and the evident curtailment during a peak time will be the first actual measurement indicators to be witnessed.

#### 3. Step 4

Quantitative impacts over the life of a Demand Response program will vary minimally among the programs. The end result is that the customer will have money that has been given in the form of an incentive or rebate. These incentives can be used in a variety of ways. The best course of action is to apply the money towards energy conservation measures that will have a long term benefit, in a virtuous circle of reducing the energy consumption while lowering operating costs.

Through the implication of long-term energy conservation efforts, the school will be able to see a greater reduction in its power bill. Additionally, with the school's ability to produce self-generated power further incentive payments will be experienced.

#### 4. Step 8

Curtailment in any program will incur some sort of inconvenience to the customer. The reduction of 200kW to 300kW in a Demand Response situation is our estimate for the study. This assumption is greatly mitigated by the means the Naval Postgraduate School has to meet the committed curtailment amount. Through self generation, the school is able to produce as much as 350kW through the startup of two generators. The generators help to alleviate any overly aggressive assumptions

## D. DIFFERENCES

The following steps in the cost benefit analysis vary amongst each program. Each program is discussed separately through steps 2, 5, and 7. Step 2 details the programs and discusses the costs, benefits and parameters. Step 5 discusses the monetary impact of each program. Step 7 sums the costs and benefits. We conclude the analysis discussing major points.

### 1. Demand Bidding Program (E-DBP)

The Demand Bidding Program is voluntary; it operates year round and allows for a day ahead or day of 'bid in' load reduction. The curtailment window is from 1200 to 2000 Monday through Friday and it excludes the weekends and holidays.

For this particular program there are two different notification time choices. The first is being notified a day ahead of the event. When notified a day ahead, the customer submits their amount of curtailment that afternoon and then is required to fulfill that promise in the next day, when the utility company makes the request. For day ahead notification, the incentive payment is $.50/kW reduction for each hour.

The second notification time is the day of the event. The customer submits their amount of curtailment to the utility company and the company replies back its acceptance in approximately fifteen minutes, and the customer must curtail the promised amount within the hour of being notified. For day of notification the incentive payment is $.60/kW reduction for each hour.

This program does not have a penalty for non-compliance. Any additional metering is supplied by PG&E.

The monetary impact from the Demand Bidding Program is deduced by the guidelines set above with 200kW curtailment for a time period of 6 hours. For the day ahead and day of notification times, respectively, the incentives are $600 and $720 per event.

Since this program is voluntary the sum of the benefits and costs will depend upon the actual number of curtailment events that are accepted during the year

### 2. Peak Choice

This is a flexible semi-customized Demand Response program based on the operational requirements of the customer. The customer can select how frequently they will participate, how long the curtailment event will be, and adjust several other factors to fit their need.

This program only applies during the peak months from May to October. The window of curtailment is from 1300 to 1900 on the weekdays, excluding holidays or 24 hours a day, seven days a week. The customer can adjust as necessary.

Notification times can be adjusted from any of the following: two days, one day, 4.5 hours and 30 minutes ahead. The curtailment level as mentioned earlier can vary and there are two different types, Best Effort and Committed. Best Effort means the customer meets set curtailment levels for each event. Committed means a curtailment load is established at enrollment.

The incentives are based on the notification times. Committed incentives vary based on customer program selections but they are typically $.15/kW per eligible load reduction. Best effort incentives are greater for the shorter amount of notification time. For a 30-minute notification time the rate is $1.00/kW reduction per hour. For two day ahead events the rate is $.40/kW reduction per hour.

Penalties are applicable in cases where the customer is in a committed contract. The penalty is 150 percent of capacity incentive value and is prorated hourly. For best effort contracts there is not a penalty. Metering is paid for by PG&E.

The monetary impact of this program is filled with variables. For the analysis we used the 30-minute notification time under the best effort contract and $1200 was the incentive amount for a six-hour 200kW/hr curtailment. Over time, we expect that the school would be able to use the incentive payments to build a more energy efficient campus. The utility bill will be reduced through the use of new technology and better equipment that was bought with the DR incentive payments

### 3. Business Energy Coalition (E-BEC)

The Business Energy Coalition is a mandatory program. BEC members work together to achieve collective demand-reduction goals; not just individual ones enjoying the added flexibility and control of being part of the group. The BEC program conducts a thorough Demand Response assessment and works closely with member-facility staff to create a custom step-by-step protocol designed to achieve their committed reduction goal. (PG&E 2008)

The program is year round instead of just the peak summer months. The curtailment window is similar to the previously mentioned programs, noon to 2000 Monday through Friday, excluding weekends and holidays.

The notification time varies for this program and there is no incentive for different times. The notification time can be anywhere from a day ahead to one hour ahead. Incentive payment for this program is $50/kW annually based on the committed load reduction. There is not a penalty however there is $25/kW annually put into a reserve fund for noncompliance. Based off of 200kW curtailment the amount of rebate could be as high as $10,000 annually with half that being put into the reserve fund.

### 4. ENERNOC

As an aggregator, ENERNOC offers contract periods that vary for each customer. The operating months are from May to October, and the curtailment windows lie between 1100 and 2000 kW, and are usually for two to six hours.

The curtailment level varies and a bid is established five days before the end of the month for the amount of curtailment in the following month. The incentive payment for curtailment is anywhere from 50-70% less than what the customer would receive from doing a program through the utility company. Since ENERNOC is an aggregator, they protect their customers from penalties that they would incur with the utility. Since ENERNOC provides this security their service is not a free one and while the consumer does not pay for the service directly they do see a reduction in the incentive. For a 30 minute ahead warning time the Naval Postgraduate School could expect to see annual payments of up to $8,000. This baseline of $8000 is based off the contractual amount of 200kW and is actually attainable whether or not there is an actual curtailment event.

### 5. Summary

Each program has the ability to get the school fully engaged in a rewarding and beneficial Demand Response operation. Incentives are based on notification time and the particular rates that correspond with that time.

Penalties are a deciding factor in the selection of the right program for the Naval Postgraduate School. Due to operational commitments, there may be times that meeting a curtailment level will be unfeasible. Programs with penalties are not feasible because there is not a system in place within the Navy's budget to be able to pay for them. Because of penalty fees, non-penalty programs surface to the top of the selection process.

There are two of the above programs that do have penalties assigned to them. The first is the Peak Choice program. This program offers a committed contract however; the incentive payment for this contract is less than the 'best effort' contract that is offered under the same Peak Choice option. Therefore we have ruled out the committed contract under Peak Choice.

The second program that has an assigned penalty is the E-BEC. Instead of actually paying a penalty the program already accounts for a period that the customer may not be able to curtail. This is done through payments into a reserve fund that act as a backup to non-compliance periods.

The final chapter provides a brief summary of our study and presents a recommendation made from the current methodology and analysis. This includes a recommendation to the Naval Postgraduate School so that we can incorporate the best Demand Response program for our needs.

# V. CONCLUSIONS AND RECOMMENDATIONS

## A. INTRODUCTION

The first two chapters of our thesis brought awareness to the reader on the history of Demand Response, technological advances that make the program more feasible, and current issues in the news concerning Demand Response and energy conservation. The third chapter introduced our methodology into figuring out the best way to derive the relative value of each potential Demand Response program that is available. In the fourth chapter we delivered an analysis of the different programs and how they related to the methodology. Our recommendations will follow and they are based off of the analysis that was done in the previous chapter. The recommendation is our attempt to identify the best possible Demand Response program for the Naval Postgraduate School to enroll in.

## B. RECOMMENDATIONS

| | 200 kW | 6 Hours | Average of 7 curtailments per season | 30 minutes ahead |
|---|---|---|---|---|
| **Curtailment Periods** | **Days** | **Days** | **Days** | Rate per kW |
| **Programs** | 0 | 5 | 10 | |
| **Peak Choice** | $0.00 | $6,000.00 | $12,000.00 | $1.00 |
| **Business Energy Coalition (E-BEC)** | $0.00 | $10,000.00 | $10,000.00 | $50.00 |
| **Demand Bidding Program (E-DBP)** | $0.00 | $3,600.00 | $7,200.00 | $0.60 |
| **ENERNOC** | $8,000.00 | $8,000.00 | $8,000.00 | $45.00 |
| | | $1,350.00 | $2,700.00 | |
| | | $9,350.00 | $10,700.00 | |

Figure 3. Demand Response Programs and Incentives Chart

After a full analysis of the available Demand Response programs we devised a graph to represent the possible incentives that each program could realize. Incentives alone are not the determining factor however; they will make up a majority of our recommendation.

The graph above depicts expected values from each program for curtailment periods in a season of zero, five and ten days. Each one of these periods would last for up to six hours. There are some differences in the amount of times each program is actually called into action. This difference varies slightly and our curtailment events are based off the average from each event. Rates are by kilowatt hour except for the rate from ENERNOC which is based off the amount of hours for the year.

The Demand Bidding Program quickly establishes itself as the least attractive option. This program is also the most difficult for the customer as they submit actual bids for curtailment when the time comes. There is not a lot of incentive for the program regardless of the amount of curtailment periods in the season.

The third best option is the Business Energy Coalition. This package is actually called upon the least out of all of the options. Curtailing 200kW for this program results in an incentive of $10,000 however, the penalty can make this amount considerably less. As mentioned in the previous paragraph if the contracted curtailment amount is not met there is approximately a 50% reduction in the incentive. This program is mandatory so there is no escaping a period of curtailment.

The two remaining programs are both voluntary and come with decent incentives. The major difference between the two programs is that with ENERNOC you get an incentive check regardless of how many curtailment events there are. With Peak Choice there must be curtailment times for an incentive check to be awarded at the end of the season.

Peak Choice offers more to the customer if there are several events. The contract incentives escalate as events increase. If there are just five-six hour events then the incentive is $6,000 but when the amount of events increases to ten-six hour events the incentive increases to $12,000. The Peak Choice program has the ability to challenge the ENERNOC program if there are more than eight events.

With the ENERNOC program the customer actually benefits immediately and does not have to be concerned with how many curtailment events there are. The contract has an initial value of $8,000 and if there are curtailment events then there is an additional energy payment that is made. This energy payment is initially at $1,350 when there are five-six-hour events and increases to $2,700 when the events increase to ten. The totals for five and ten events are $9,350 and $10,700 respectively.

Peak Choice and ENERNOC are both viable programs for NPS to enroll in. ENERNOC has the ability to provide immediate incentives no matter the outlook on the future season. Peak Choice operates from May to October and ENERNOC operates from June to October. With a long season Peak Choice has the ability to have more events and thus return a larger incentive. Both of the programs are voluntary and pose no real risks to the customer.

## C. BARRIERS TO IMPLEMENTATION

There must be a shift in the thought process of government installations to realize that Demand Response programs do not mean loss of control or power during a curtailment period. Installations do not have to turn over control of their energy or suffer operationally. With advanced technology and more flexible contracts a wide variety of programs are available to best suit the customer.

Developing the proper contracting vehicle to attain these services has become a problem for contracting offices that has previously wanted to initiate Demand Response programs. Most contracting offices have to follow the guidelines of the Federal Acquisitions Regulations Manual (FAR) for contracting services for military installations. The only problem is the FAR does not cover the process for implementing contracts for DR, mainly because this service is relatively new for military installations and these programs are not the typical service agreements that require payment for performing an actual service or extra penalties if the curtailment is not a success. To help alleviate some of the difficulty DESC has set up Demand Response Master Agreements, on their website, to assist contracting officers with these hybrid contracts. Additionally, the DR guide is also available, to aid the facility managers and contractors with pertinent questions to consider when engaging in talks with regarding DR programs.

## D. AREAS FOR FURTHER RESEARCH

We suggest further research or changes in the areas of EMCS and Auto-DR. To be able to fully experience the benefits of the school's current EMCS they should employ one person that monitors, records, analyzes and reports the data that this system gives. By understanding the full the capabilities of the EMCS installed on NPS not only can further curtailment options be available but this could also be an asset in long-term energy efficiency efforts. After understanding these capabilities, further research can be done on the feasibility of a complete Auto-DR. Auto-DR programs can potentially provide customers automated electronic pricing signals that improve the reliability of the Demand Response programs so they can achieve the same operations status as conventional generation efforts with little to no intervention from the daily operations of the public works department.

## E. FINAL THOUGHTS

The need to 'go' or 'get green' is ever increasing in today's society. Military installations and the Federal Government in general will be called upon to lead the way in everything from Demand Response programs to energy conservation and the use of renewable energy. Demand Response is becoming increasingly more attractive and practical with the advances being made in technology. While all energy conscious movements cost a great deal of investment, Demand Response programs can be an efficient way to spur on longer term energy conscious movements. Incentives brought in by responding to peak curtailment situations can be applied to energy conservation efforts and allow an installation to move forward more quickly into becoming more 'green'.

Demand Response customers also provide an even greater benefit to society. The more Demand Response customers a utility provider has in their clientele the more likely they are to avoid the start up of a peak performance plant during high demand times. This is a great value to the public since peak performance plants cost millions to maintain and can emit gross amounts of pollution into the environment when they are used.

Overall the Naval Postgraduate School can experience incentive benefits by enrolling in the right Demand Response program.  The school can also give back to the local area and improve the local outlook on the school.  Finally, by becoming a Demand Response customer the school can begin to move quickly to becoming more energy conservation conscious and this will provide great dividends to helping the institution to stay off of the Base Realignment and Closure list.

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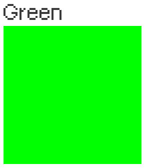
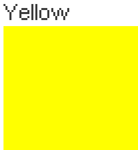
# APPENDIX A PG&E CURTAILMANT STAGES

| Status Color | Notice | Conditions |
|---|---|---|
| | NO CURTAILMENT OPERATION IN PROGRESS | As of this time, **NO CURTAILMENT OPERATION IS IN PROGRESS** for commercial and industrial customers on Pacific Gas and Electric Company's Non-Firm Service Program. Electric supplies and system conditions are expected to be sufficient to meet Pacific Gas and Electric Company's forecasted loads. No action by Pacific Gas and Electric Company's customers is required at this time. If a Non-Firm operation becomes necessary, Pacific Gas and Electric Company will activate the non-firm notification system. |
| Green  | NO CURTAILMENT OPERATION IN PROGRESS | **NO CURTAILMENT OPERATION IS IN PROGRESS OR IS FORECASTED FOR THIS WEEKEND** for Pacific Gas and Electric Company's Non-Firm Service Program. Electric supplies and system conditions are expected to be sufficient to meet Pacific Gas and Electric Company's forecasted loads. No action by Pacific Gas and Electric Company's customers is required at this time. If a Non-Firm operation becomes necessary, Pacific Gas and Electric Company will activate the non-firm notification system. |
| Yellow  | ALERT | The California Independent System Operator (CAISO) has issued an **ALERT** which indicates that the operating reserves in the day ahead market are forecasted to be less than the CAISO's Minimum Operating Reserves criteria. No action by Pacific Gas and Electric Company's customers is required at this time. If a Non-Firm operation becomes necessary, Pacific Gas and Electric Company will activate the non-firm notification system. |
| Yellow  | WARNING | The California Independent System Operator (CAISO) has issued a **WARNING**, which indicates that the operating reserves in the hour ahead market are forecasted to be less than the CAISO's Minimum Operating Reserves criteria. No action by Pacific Gas and Electric Company's customers is required at this time. If a Non-Firm operation becomes necessary, Pacific Gas and Electric Company will activate the non-firm notification system. |

| Status Color | Notice | Conditions |
| --- | --- | --- |
| Yellow | STAGE 1 EMERGENCY | The California Independent System Operator (CAISO) has issued a **STAGE 1 EMERGENCY** which indicates that the operating reserves in the real-time market are forecasted to be less than the CAISO Minimum Operating Reserves criteria. There is a potential for a Non-Firm operation. All Pacific Gas and Electric Company customers are requested to VOLUNTARILY curtail nonessential electric loads. |
| Yellow | THERE IS A POTENTIAL FOR A NON-FIRM OPERATION TODAY | Constraints within Pacific Gas and Electric Company's electric transmission system or the California Independent System Operator's (CAISO) control area may impair Pacific Gas and Electric Company's ability to meet the demands of our other customers. As such, **there is a potential for a Non-Firm operation later today.** |
| Yellow | STAGE 2 EMERGENCY IS IN EFFECT TODAY FROM (START TIME) TO (END TIME). **NO NON-FIRM CURTIALMENT OPERATION IS REQUIRED AT THIS TIME.** | The California Independent System Operator (CAISO) has issued a **STAGE 2 EMERGENCY** which indicates that the operating reserves in the real-time market are forecasted to be less than five (5) percent. **Customers on Pacific Gas and Electric Company's Non-Firm Service Program ARE NOT being requested to curtail their electric load down to their contracted Firm Service Level at this time.** Non-Firm Customers should be ready to curtail their electric load down to their contracted Firm Service Level should system conditions change. All Pacific Gas and Electric Company customers are requested to VOLUNTARILY curtail nonessential electric loads.. |
| Red | STAGE 2 EMERGENCY NON-FIRM CURTAILMENT OPERATION IS IN EFFECT TODAY FROM (START TIME) TO (END TIME). | The California Independent System Operator (CAISO) has issued a **STAGE 2 EMERGENCY** which indicates that the operating reserves in the real-time market are forecasted to be less than five (5) percent. Customers on Pacific Gas and Electric Company's Non-Firm Service Program are required to curtail their electric load down to their contracted Firm Service Level during the curtailment period stated above. All other customers are requested to VOLUNTARILY curtail nonessential electric loads. |

| Status Color | Notice | Conditions |
| --- | --- | --- |
| Red | A NON-FIRM CURTAILMENT OPERATION HAS BEEN SCHEDULED FOR TODAY FROM (START TIME) TO (END TIME). | Constraints within Pacific Gas and Electric Company's electric transmission system or the California Independent System Operator's (CAISO) control area has impaired Pacific Gas and Electric Company's ability to meet the demands of our other customers. To help relieve the constraints, customers on Pacific Gas and Electric Company's Non-Firm Service Program are required to curtail their electric load down to their contracted Firm Service Level during the curtailment period stated above. |
| Red | STAGE 3 EMERGENCYROTATING BLOCK OUTAGES HAVE NOT BEEN IMPLEMENTED AT THIS TIME. | The California Independent System Operator (CAISO) has issued a **STAGE 3 EMERGENCY** which indicates that the operating reserves in the real-time market are forecasted to be less than 1.5 percent. Pacific Gas and Electric Company HAS NOT commenced involuntary rotating block outages for all customers at this time. |
| Red | STAGE 3 EMERGENCYA NON-FIRM CURTAILMENT OPERATION IS IN EFFECT TODAY FROM (START TIME) TO (END TIME).INVOLUNTARY ROTATING BLOCK OUTAGES HAVE NOT BEEN IMPLEMENTED AT THIS TIME. | The California Independent System Operator (CAISO) has issued a **STAGE 3 EMERGENCY** which indicates that the operating reserves in the real-time market are forecasted to be less than 1.5 percent. Customers on Pacific Gas and Electric Company's Non-Firm Service Program are required to curtail their electric load down to their contracted Firm Service Level during the curtailment period stated above. Pacific Gas and Electric Company will commence involuntary rotating block outages for all customers including the non-firm customers. |
| Red | STAGE 3 EMERGENCYA NON-FIRM CURTAILMENT OPERATION IS IN EFFECT TODAY FROM (START TIME) TO (END TIME).PACIFIC GAS AND ELECTRIC COMPANY HAS COMMENCE INVOLUNTARY ROTATING BLOCK OUTAGES FOR ALL CUSTOMERS INCLUDING THE NON-FIRM CUSTOMERS. | The California Independent System Operator (CAISO) has issued a **STAGE 3 EMERGENCY** which indicates that the operating reserves in the real-time market are forecasted to be less than 1.5 percent. Customers on Pacific Gas and Electric Company's Non-Firm Service Program are required to curtail their electric load down to their contracted Firm Service Level during the curtailment period stated above. Pacific Gas and Electric Company has commence involuntary rotating block outages for all customers including the non-firm |

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# APPENDIX B EPACT 2005 LANGUAGE ON DEMAND RESPONSE AND SMART METERING

SEC. 1252. SMART METERING.
(a) IN GENERAL.—Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following:
''(14) TIME-BASED METERING AND COMMUNICATIONS.—
(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer H. R. 6—371 classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.
''(B) The types of time-based rate schedules that may be offered under the schedule referred to in Sub-paragraph (A) include, among others—
''(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be preestablished and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;
''(ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;
''(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and
''(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.
''(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a timebased rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.
''(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.
''(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.
''(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).''. H. R. 6—372
(b) STATE INVESTIGATION OF DEMAND RESPONSE AND TIMEBASED METERING.—Section 115 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2625) is amended as follows:
(1) By inserting in subsection (b) after the phrase ''the standard for time-of-day rates established by section 111(d)(3)'' the following: ''and the standard for time-based metering and communications established by section 111(d)(14)''.
(2) By inserting in subsection (b) after the phrase ''are likely to exceed the metering'' the following: ''and communications''.
(3) By adding at the end the following:

‘‘(i) TIME-BASED METERING AND COMMUNICATIONS.—In making a determination with respect to the standard established by section 111(d)(14), the investigation requirement of section
111(d)(14)(F) shall be as follows: Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other Demand Response programs.’’.

(c) FEDERAL ASSISTANCE ON DEMAND RESPONSE.—Section 132(a) of the Public Utility
Regulatory Policies Act of 1978 (16 U.S.C. 2642(a)) is amended by striking ‘‘and’’ at the end of paragraph (3), striking the period at the end of paragraph (4) and inserting ‘‘; and’’, and by adding the following at the end thereof: ‘‘(5) technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in Demand Response programs.’’.

(d) FEDERAL GUIDANCE.—Section 132 of the Public Utility Regulatory Policies Act of 1978 (16
U.S.C. 2642) is amended by adding the following at the end thereof:

‘‘(d) DEMAND RESPONSE.—The Secretary shall be responsible for—

‘‘(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;

‘‘(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of Demand Response programs; and

‘‘(3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing
Congress with a report that identifies and quantifies the national benefits of Demand Response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.’’.

(e) DEMAND RESPONSE AND REGIONAL COORDINATION.—

(1) IN GENERAL.—It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable Demand Response services to the public.

(2) TECHNICAL ASSISTANCE.—The Secretary shall provide technical assistance to States and regional organizations formed by two or more States to assist them in—

(A) identifying the areas with the greatest Demand Response potential; H. R. 6—373

(B) identifying and resolving problems in transmission and distribution networks, including through the use of Demand Response;

(C) developing plans and programs to use Demand Response to respond to peak demand or
emergency needs; and

(D) identifying specific measures consumers can take to participate in these Demand Response programs.

(3) REPORT.—Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the Commission shall prepare and publish an annual report, by appropriate region, that assesses Demand Response resources, including those available from all consumer classes, and which identifies and reviews—

(A) saturation and penetration rate of advanced meters and communications technologies, devices and systems;

(B) existing Demand Response programs and time-based rate programs;

(C) the annual resource contribution of demand resources;

(D) the potential for Demand Response as a quantifiable, reliable resource for regional
planning purposes

(E) steps taken to ensure that, in regional transmission planning and operations,
demand resources are provided equitable treatment as a quantifiable, reliable resource
relative to the resource obligations of any load-serving entity, transmission provider,
or transmitting party; and

(F) regulatory barriers to improve customer participation in Demand Response, peak reduction and critical period pricing programs.

(f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.—It is the policy of the
United States that time-based pricing and other forms of Demand Response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and Demand Response systems shall be facilitated, and unnecessary barriers to Demand Response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the

policy of the United States that the benefits of such Demand Response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.

(g) TIME LIMITATIONS.—Section 112(b) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(b)) is amended by adding at the end the following:

''(4)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to teach electric utility for which it has ratemaking authority) and each non-regulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to the standard established by paragraph (14) of section 111(d).

''(B) Not later than 2 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each non-regulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to the standard established by paragraph (14) of section 111(d).''.

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